ALTERNATIVE REGULATION PLAN

This Alternative Regulation Plan (the "Plan") is established pursuant to 30 V.S.A. § 218d. The Plan establishes the method by which the Public Service Board (the "PSB" or the "Board") will regulate the rates charged for all jurisdictional products and services offered by Vermont Gas Systems, Inc. ("VGS" or the "Company"), during the term of the Plan.

1. Term of the Plan.

   a. The Plan will commence on October 1, 2012, and have a term that will expire on September 30, 2015, unless extended under Subparagraph 1b of this Plan.

   b. This Plan shall be extended for a one-year term beginning on October 1, 2015, and expiring on September 30, 2016. No further extensions of this Plan will be permitted.

      i. By January 31, 2013, VGS and the DPS will evaluate the existing criteria used to assess the effectiveness of the previous Alternative-Regulation Plan and will advise the PSB as to whether these or different or additional criteria will be used to evaluate this Plan's effectiveness.

      ii. Twelve months before expiration of the initial or any renewal terms of the Plan, VGS will submit its assessment of the Plan's effectiveness to the PSB and DPS.

iii. Eleven months before expiration of the initial or any renewal term of this Plan, the DPS will submit its assessment of the Plan's effectiveness to the PSB and VGS.

c. During the term of this Plan, no capital investments associated with the Phase I Project approved in Docket No. 7970 shall be included in rates. Any expenses related to Phase I for which cost recovery is requested shall be separately identified and supported in the base rate filing.

2. Regulatory Framework.

a. Sections 218(a), 225, 226, 227 and 229 of Title 30 will continue to apply except as specified herein.

b. The objective of this Plan is to regulate VGS's rates as provided herein rather than through litigated, cost of service ("COS") investigations, even though the Company's rates will still be based on its COS.

3. Cost of Service.

a. VGS shall be entitled under this Plan to have rates set based on the revenue required to recover "known and measurable" costs in the provision of service. VGS' COS (including expenses and rate base) shall be subject to the "known and measureable" standard and shall be calculated in accordance with traditional ratemaking principles applied by the PSB, as set forth in Attachment 5, except that the Company's earnings shall be determined and shared in accordance with the "Earnings Sharing Mechanism" (the "ESM") established by

Paragraph 5 of this Plan, and the Company shall be entitled to recover its gas costs in accordance with the "Purchased Gas Adjustment" (the "PGA") established by Paragraph 4 of this Plan.

b. The COS of VGS shall be determined based on traditional ratemaking policy, as established by Board precedent, including specifically the following policies:

   i. the COS will be based on an historic and adjusted test year and will include the concept of weather normalization;

   ii. adjustments to costs from the historic to the adjusted test year will be based on known and measurable changes;

   iii. expenses for DSM shall be amortized over a three-year period, unless modified by paragraph 3e. iv. certain expenses, such as outside services and legal expenses, shall be determined using a three-year average; and

   v. the COS shall exclude donations, lobbying expenses and other expenses not traditionally allowed in rates, as established by previous Board decisions.

c. The capital structure ("weighted average cost of capital" or "WACC") is to be composed of appropriate shares of shareholder equity and short and long term debt. The WACC is to be based on the actual debt to equity ratio, subject to a cap of 55 percent for the equity share. If shareholder equity exceeds the "cap," the equity component shall be imputed to the 55 percent level and the excess shall be apportioned between long-term and short-term debt based on a three-year average of the ratio between long-term and short-term debt using the most current 3 years including the test year. The 3 year average shall be determined using the monthly financial statements as submitted to the DPS, adjusted for known and measurable changes in debt and equity for the remaining months of the adjusted test year (rate year). The return on equity shall be initially set at 9.75% and, for purposes of the Annual Rate Adjustment described in Paragraph 5, shall be adjusted each year thereafter at one-half the change in the composite 10-Year Treasury Note Rate as provided in this subparagraph.

i. The change shall be based on the composite 10-Year Treasury Note Rate as published by the U.S. Department of the Treasury for each date between July 15 and August 15 of the then-current Plan year as compared to the same time period during the prior Plan year.

ii. For greater clarity, the data source for U.S. Treasury Note rates is currently located at: http://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/textview.aspx?data=yield

iii. If the U.S. Department of the Treasury ceases to publish this rate during the life of this Plan, VGS and the DPS will work cooperatively to identify a replacement index rate.

iv. The change in return on equity as calculated in accordance with this paragraph shall be limited to no more than 100 basis-points difference per Plan year.

v. In any Plan year where the change in return on equity is limited to 100 basis points, in the subsequent Plan year the return on equity shall also be adjusted for one-half of the difference between the actual change calculated as provided in Clause ii of this subparagraph.

d. The gas-charge provisions of the Company's rates will be adjusted quarterly in accordance with the PGA, and the non-gas charge provisions will be adjusted annually in accordance with the ESM, as provided in Paragraphs 4 and 5 of this Plan, respectively.

e. Rates may be modified to reflect the implementation of a natural gas energy efficiency charge pursuant to a Board Order.

4. Quarterly PGA Adjustments.

a. Quarterly, no later than the third-to-last business day of the month, VGS shall notify the PSB and the DPS of the Quarterly PGA Adjustment to be made (the "Quarterly PGA Adjustment") commencing the first billing cycle beginning three months forward; for example, if VGS notifies the PSB and the DPS of an adjustment on November 25 of any Plan year, that adjustment shall be effective in the first billing cycle in February.

b. The rate year reflected in the Quarterly PGA Adjustments shall be the twelve-month period beginning two months forward; for example, if VGS notifies the PSB and the DPS on November 25 of any Plan year, the rate year shall be January through December.

i. The first such notification shall occur in November 2012 and shall thereafter occur quarterly *(i.e.,* May, August, November and February).

ii. The Quarterly PGA Adjustment shall take effect on a bills-rendered basis.

iii. VGS shall give individual notice to customers of each Quarterly PGA Adjustment of not less than 55 days before bills are rendered and not less than 25 days before service is rendered.

c. The last Quarterly PGA Adjustment in any calendar year will be made at the same time as the Annual Rate Adjustment, for which provision is made in Paragraph 5 of this Plan.

d. All Gas Costs will be collected through the Gas Charge to be collected from firm customers. The Gas Charge will be re-calculated quarterly, as an average cost per ccf based on forecasted costs and volumes for the next 12 months, beginning two months forward and to correct for any under- or over-collection of costs during the previous quarter, as follows:

i. Gas Costs to be recovered through the Gas Charge under the Quarterly PGA Adjustment are costs related to the purchasing, storing, production, and transporting of natural gas to serve sales customers. Gas Costs include:

a) Firm commodity costs (including spot purchases);

b) Interruptible commodity costs (including spot purchases);

c) Storage withdrawals, including variable injection and withdrawal costs;

d) Peaking commodity costs;

e) Off-system commodity costs;

f) Propane air commodity (propane only) costs;

g) TCPL, Union or other pipeline tolls and charges;

h) Storage-related demand charges;

i) Peaking demand charges;

j) Hedging positions: natural gas, oil, and foreign exchange;

k) Hedging instrument premiums;

l) Canadian federal or provincial taxes imposed on gas purchases or pipeline tolls;

m) System losses; and

n) Other gas costs that may occur and are appropriately charged to FERC accounts 800 through 805.

ii. The definition and determination of these components is shown in subparagraph f. In its quarterly supply filings pursuant to subparagraph 7b of this Plan, VGS will highlight any changes to its supply portfolio or to the definitions and determinations shown in subparagraph f.

iii. Each quarter, no later than the third to last business day of the month, VGS will make a filing which includes:

a) Forecasted Gas Costs for the 12 months beginning two months forward. Forecasted Gas Costs will be calculated based on then-current pipeline tolls, fixed-price contracts and market forecasts for unhedged indexed supplies, minus projected interruptible and off-system sales revenue;

b) Forecasted Gas Sales Volumes for the 12 months beginning two months forward, based on projected numbers of customers and 10-year normal weather;

c) Actual Gas Costs for the previous quarter, net of interruptible and off-system revenue;

d) Actual Firm Gas Sales Volumes for the previous quarter;

e) Actual Firm Gas Charge Revenues for the previous quarter;

f) The proposed new Gas Charge, which will be calculated to recover on a 12-month basis Forecasted Gas Costs and to discharge any Adjustment required by over- or under- collection of Gas Costs from the previous quarters.

e. The Gas Charge will be calculated using the following formula:

GAS CHARGE= (12-MONTH COST FORECAST± ADJUSTMENT)/12-MONTH VOLUME FORECAST

Where:

Gas Charge	=	Price per ccf for gas sold to firm customers.
12-Month Cost Forecast	=	Forecast of Gas Costs identified above.
Adjustment	=	The difference between previous quarters' Actual Gas Costs (net of interruptible and off-system revenue) and Actual Firm Gas Charge Revenues.
12-Month Volume Forecast	=	Forecast of firm Gas Sales Volumes for the 12 months beginning 2 months forward, based on projected numbers of customers and 10-year normal weather.

f. For greater specificity, and consistent with the methods and sources used in the adjusted test year, the determination of the components of the 12-Month Cost Forecast are described more fully below:

i. Firm commodity costs, including spot purchases, are non-storage, non-peaking supplies incurred for resale to the firm market and will be based on the contractual pricing and volumes associated with VGS's supply contracts in effect for the twelve month forecast period.

a) If VGS's supply contracts expire during the twelve-month forecast period and no replacement contracts have been executed, the remaining months of the forecast period will reflect the pricing of the existing contracts.

b) Spot gas that has not been pre-purchased will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period to the spot market purchase point.

c) NYMEX-based contracts will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period.

d) AECO or Empress-based contracts will priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current NYMEX (Henry Hub) to AECO or Empress basis differential for the forecast period.

e) The then-current NYMEX (Henry Hub) strip and basis differential will be based on the average of the last five trading days ending between two and five trading days before filing.

f) Contracts stated in Canadian dollars will be expressed in U.S. dollars based on the same five trading days as used for NYMEX and basis differential.

ii. Interruptible commodity costs (including spot purchases) will be determined as follows:

a) Interruptible commodity costs are all commodity costs incurred for resale to the interruptible market and will be based on the contractual pricing and volumes associated with VGS's supply contracts in effect for the twelve-month forecast period, including any pre-purchase of spot gas.

b) If VGS's supply contracts (excluding the pre-purchase of spot gas) expire during the twelve-month forecast period and no replacement contracts have been executed, the remaining months of the forecast period will reflect the pricing of the existing contracts.

c) Spot gas that has not been pre-purchased will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period to the spot market purchase point.

d) NYMEX-based contracts will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period.

e) AECO or Empress-based contracts will priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period.

f) The then-current NYMEX (Henry hub) strip and basis differential will be based on the average of the last five trading days ending between two and five trading days before filing.

g) Pre-purchased spot gas purchases will be reflected at the volumes and price agreed to in a confirmation transaction.

h) Contracts stated in Canadian dollars will be expressed in U.S. dollars based on the same five trading days as used for NYMEX and basis differential.

iii. Storage withdrawals, including variable injection and withdrawal costs, will be determined as follows:

a) Variable storage injection and withdrawal costs will be reflected at the rates in place at the time of the PGA filing.

b) Storage withdrawals are volumes of gas withdrawn from storage, including fuel, and will be priced using the projected storage weighted average cost of gas ("WACOG"). The projected WACOG will reflect projected injection and withdrawal volumes, current market prices for injected volumes, including the impact of any hedge positions in effect for storage injections, and then-current TCPL fuel ratio for storage withdrawals.

iv. Peaking commodity costs will be determined as follows:

a) Peaking commodity costs will be based on the contractual pricing and volumes associated with VGS's peaking supply contracts in effect for the twelve-month forecast period.

b) Market-based pricing such as an "Iroquois price" will be determined from then-current NYMEX (Henry Hub) strip for the forecast period plus a basis differential using the same 5 trading days previously described.

v. Off-system commodity costs will be priced at Dawn or Parkway depending on the point of sale and priced at the then-current NYMEX (Henry Hub) strip for the forecast period adjusted for the then-current basis differential.

vi. Propane commodity costs will be based on the then-current actual propane WACOG and will only include the cost of propane consumed, not any other costs of operating the propane air plant.

vii. TCPL and other pipeline tolls and charges will be established using the TCPL or other pipeline tolls to be in effect during the contract period applied to the contractual contract demand for the forecast period. Projected increases or decreases in such pipeline tolls will not be included until approved by the applicable regulatory agency, i.e., National Energy Board. Tolls stated in Canadian dollars will be expressed in U.S. dollars based on the then-current rate as defined above.

viii. Storage-related fixed charges will be based on the fixed charges pursuant to the pricing provisions contained in any storage contract in effect during the twelve-month forecast period.

ix. Peaking demand charges will be set based on the contractual demand charges, if any, established in the peaking supply contracts in effect for the twelve-month forecast period.

x. Hedging positions for natural gas, oil, and foreign exchange will reflect all hedges executed at the time of the PGA filing and in effect during the twelve-month forecast period, whether for firm or interruptible customers.

xi. Hedging instrument premiums will reflect any premiums actually incurred by VGS for the twelve month forecast period.

xii. System losses will be based on VGS's historical actual system losses, including company use.

xiii. Other gas costs include costs that may occur and are appropriately charged to FERC accounts 800 through 805, for example, the purchase of LNG or bio-methane. To the extent VGS includes any other gas costs in its quarterly PGA filing, such costs will be identified in the supporting information and will be described in the quarterly reports described in subparagraph 7b of the Successor Alternative Regulation Plan.

g. Nothing in this Plan will be interpreted as preventing the DPS from asking the PSB to investigate or the PSB from investigating the prudence of the gas costs charged to VGS customers under the PGA.

5. Annual Rate Adjustments.

a. Annually, no later than August 28 of any Plan year, VGS shall notify the DPS and the PSB of any increase or decrease in its rates (if any) charged to firm customers to reflect the changes to VGS's rates determined in accordance with Paragraph 3 of this Plan (the "Annual Notice").

b. The increase or decrease in rates shall be determined as provided in this subparagraph b and consists of three steps involving the determination of:

- The Revenue Cap in accordance with a predetermined escalation formula;
- The Required Revenue; and
- Rates based on a comparison of the Required Revenue with the Revenue Cap.

i. The Revenue Cap will be determined as using the following formula:

REVct= OCct-1 * (1+1NFLATION-X) * CUSTOMERSt +NON-OPERATING COSTSt± EXOGENOUS FACTORS± EXCLUSIONS

Where:

REVct	=	Revenue Cap for rate year t
OCct-1	=	Operating Cost Cap for rate year t-1
INFLATION	=	(see below)
X	=	(see below)
CUSTOMERSt	=	Projected customers for rate year t
EXOGENOUS FACTORS	=	(see below)
EXCLUSIONS	=	(see below)
NON-OPERATING COSTSt	=	(see below)

ii. In the first year of the Plan, the *Operating Cost Cap* will be equal to $319 per customer. Thereafter, in each subsequent year of the Plan the Operating Cost Cap will be determined by applying the formula (1+1NFLATION-X) to the previous year's Operating Cost Cap.

iii. The *inflation factor* in the Revenue Cap formula will be based on the historical rate of inflation for New England for the most recent 12 months ending before VGS's rate filing. Inflation will be based on CPI data for the Northeast published by the US Department of Labor- Bureau of Labor Statistics.

iv. The *X Factor* under the Operating Cost Cap will be .39%

v. VGS will prepare a forecast of the average number of customers during the rate year.

vi. *Non-Operating Costs* for the Revenue Cap formula will be subject to the "known and measurable standard" and based on VGS's budget for the rate year. This shall be comprised of all cost-of-service components (other than

Gas Costs) not covered by the Operating Cost Cap, including depreciation, amortization, property taxes, income taxes, other taxes, return on rate base, interest expenses, and other income.

vii. *Exogenous Factors* are events beyond the control of VGS, which affect its costs and the inclusion of which in rates is justified. Examples of Exogenous Factors include decisions of regulatory bodies or governments or changes in accounting guidelines. To trigger a rate adjustment, an Exogenous Factor will meet the following criteria:

- It cannot be under the control of VGS;
- It must apply specifically to VGS's field of activity rather than to the economy as a whole; and
- It must exceed $50,000.

viii. *Exclusions* are items that affect VGS's costs and which are under VGS's control. As with Exogenous Factors, there is justification for including the full impact of Exclusions when setting rates.

a) Exclusions serve two main objectives:

- To avoid creating an incentive to avoid expenses, which would otherwise be considered desirable (for example, demand-side-management expenses would be treated as an Exclusion); and
- To adjust rates for Over-earnings or Shortfalls (see subparagraph xi below).

Except for Over-earnings or Shortfalls (see subparagraph xi below), there will be no minimum threshold for incorporating the monetary impact of an Exclusion in the performance incentive mechanism.

b) The System Expansion and Reliability Fund will be treated as an Exclusion.

ix. *Required Revenue* will be determined in the same manner as under a traditional cost-based regulatory framework.

a) Accordingly, a budgeted estimate, subject to the "known and measureable" standard, based on the forward test year will be supplied by VGS in each rate application and will deal with the following items:

- Operating expenses;
- Depreciation;
- Amortization;
- Property and other taxes;
- Deemed income taxes;
- Return on projected rate-base (13-month average); and
- Other income.

b) The return on rate base will correspond to the average cost of capital for the various components of the capital structure as authorized by the Board.

c) The only difference between Required Revenue and Revenue Cap is in the determination of Operating Expenses.

x. The formula for setting authorized rates will be as follows:

$REV_A t = REV_C t - (.5 * (REV_C t - REV_R t))$

Where:

REV_A	=	Authorized Revenue for rate year t.
REV_C	=	Revenue Cap for rate year t.
REV_R	=	Required Revenue for rate year t.

Authorized Revenue will be used to establish non-gas rates. Absent a Board- approved rate-design change, all non-gas components of rates will change by the same percentage required to collect Authorized Revenues.

xi. At the end of the rate year, Over-earnings (if any) or Shortfalls (if any) will be calculated by comparing the actual return to the authorized rate or return using the following formula:

$OE = E - E_A$

$SF = E_A - E$

Where:

OE	=	Over-earnings
SF	=	Earnings shortfall
E	=	Actual earnings, normalized for 10-year normal weather
E_A	=	Allowed earnings based on authorized rate of return plus 25 basis points and minus 50 basis points and actual 13-month average rate base, net of productivity gain sharing.

Over-earnings or Shortfalls to be included in rates will be included in the Revenue Cap as Exclusions calculated according to the following formulas:

$OE_{EXC}t = -(OEt_{-1} * .75)$

$SF_{EXC}t = (SFt_{-1} * .5)$

Where:

$OE_{EXC}t$	=	Over-earnings Exclusion applied to Authorized Revenue in rate year t.
OEt_{-1}	=	Over-earnings for year t-1 as calculated in review at end of year t-1.
$SF_{EXC}t$	=	Shortfall Exclusion applied to Authorized Revenue in rate year t.
SFt_{-1}	=	Shortfall for year t-1 as calculated in review at end of year t-1.

Provided, however, that if OE are equal to or less than 25 basis points over VGS's earnings at authorized return on equity or SF are equal to or greater than 50 basis points under VGS's earnings at authorized return on equity, no Over-earnings or Shortfalls shall be included in rates. Further, if OE are greater than 175 basis points over E_A, the over-earnings above the 175 basis points shall be fully reflected by a decrease in rates. If SF are less than 150 basis points under E_A, the shortfall below the 150 basis points shall be fully reflected by an increase in rates. For clarity, the intent of the earnings-share calculation is to have a dead band, 25 basis points above and 50 basis points below Vermont Gas's authorized return. Within the dead band no earnings sharing occurs. Below the dead band, earnings-sharing occurs 50% to customers and 50% to Vermont Gas. Above the dead band, earnings-sharing occurs 75% to customers and 25% for Vermont Gas. Further, beyond +/- 200 basis point from Vermont Gas's authorized return, 100% of the over or under earnings is collected from/ returned to customers.

xii. For purpose of determining weather-normalized earnings, the use per degree day, per customer, by firm rate class will be applied to the difference between actual degree days and degree days in the most recent base-rate filing times the actual number of customers. The resulting Mcf adjustment, by rate class, will be multiplied by the distribution charge, by rate, class to determine the weather adjustment. The calculation, by firm rate class, by month will be as follows:

$$WV = (Customers * UDD * (DD_a - DD_n)) * DR$$

Where:

WV	=	Weather Variance
Customers	=	Actual number of customers
UDD	=	Use per degree day from base rate filing
DD_a	=	Actual Degree Days
DD_n	=	Degree Days per Base Rate Filing

DR = Distribution Rate

The resulting WV will be returned to or collected from customers in the annual ESM filing.

c. The change in rates shall take effect on a bills-rendered basis effective with the first billing cycle beginning three months forward; for example, if VGS notifies the PSB and DPS on August 25 of any Plan year, the adjustment shall be effective in the first billing cycle in November.

d. The rate year shall be October through September.

e. Not later than June 30 of any Plan year, VGS shall provide the DPS and the PSB with a preliminary assessment of the anticipated increase or decrease in rates; with its Annual Notice, VGS shall also provide to the DPS a summary of the major variances in costs between its preliminary assessment and the Annual Notice.

f. With the Annual Notice, VGS shall provide the DPS and the PSB with compliance tariff sheets accompanied by documentation supporting the change.

g. VGS shall give individual notice to customers of each rate adjustment of not less than 55 days before bills are rendered and not less than 25 days before service is rendered.

h. Annually, no later than July 31 of any Plan year, VGS shall update estimates of actual customer additions for the current fiscal year.

i. Nothing in this Plan shall be interpreted as preventing the DPS from asking the PSB to investigate or the PSB from investigating any such adjustment in rates, and any such adjustment shall take effect subject to change by any final order in any docket initiated to investigate VGS's rates, such order to take effect within thirty days of the final order in such docket.

j. The DPS Consultant's report shall be filed with the Board three weeks after VGS's annual base-rate filing is submitted to the Board. The Department's recommendation regarding any rate changes proposed in the annual base-rate filing shall be submitted to the Board no later than 30 days after the filing of the Annual Notice.

6. Service Quality and Reliability Plan.

   a. VGS shall continue to comply with its existing Service Quality and Reliability Plan (the "SQRP").

   b. VGS and the DPS will attempt to develop jointly benchmarks to measure VGS's service quality and reliability performance.

      i. By June 30, 2013, VGS and the DPS will submit to the PSB, separately or jointly, recommendations for such benchmarking of VGS.

      ii. The recommendations may include incentives for above-benchmark performance by VGS.

7. Management of Gas Supply.

   a. Annually, no later than July 1 during the term of this Plan, the Company shall file with the DPS and the PSB its gas-supply plan for the gas year commencing on November 1 of that year (the "Gas-Supply Plan"), which Gas Supply Plan shall also provide an overview of the Company's strategy for procuring, storing and selling in wholesale markets natural gas required to serve its customers over a three-year period.

b. Quarterly, no later than the 15th day of each of February, May, August and November during the term of this Plan, VGS shall provide notice to the DPS and the PSB of changes to any contracts for the supply, storage, transmission or hedging of its gas supply or exchange rates, including changes to any such contracts and the rates paid or positions taken thereunder.

8. System Expansion.

a. Annually, no later than March 15 during the term of this Plan, VGS will meet with the DPS to discuss the investments made by the Company during the previous calendar year, including the cost, location and customer base therefor, to expand its system as well as the Company's preliminary plans for such investment in the current calendar year, including the cost, location and customer base therefor, and to discuss VGS's long-range plans for expansion of its system in Vermont.

b. Annually, no later than August 15 of any Plan year, VGS shall update estimates of actual customer additions for the current fiscal year and notify the DPS of any changes in its capital plans that would impact forecasts of customer additions.

c. Annually, no later than November 1 of any Plan year, VGS shall report to the PSB and the DPS on changes in energy markets or customer demand that present an opportunity for VGS to offer new services.

9. Dispute Resolution.

   a. VGS and the DPS will resolve any disputes about regulation of VGS under this Plan in accordance with the provisions of this Paragraph 9.

   b. VGS or the DPS, as the case may be, will provide notice in writing of any such dispute.

      i. For the DPS, notice shall be provided to the DPS Commissioner.

      ii. For VGS, notice shall be provided to its Chief Executive Officer ("CEO").

   c. Within 30 days of such notice, representatives of VGS and the DPS will meet to attempt to resolve the dispute.

   d. If the representatives of VGS and the DPS are unable to resolve the dispute within 60 days of such notice, the dispute will be referred to the DPS's Commissioner and VGS's CEO, who will meet at least once to attempt to resolve the dispute.

   e. If the dispute is not resolved within 90 days of such notice, either VGS or the DPS may petition the PSB to resolve the dispute, which, if appropriate, may be treated by the PSB as a petition to amend the Plan under Paragraph 10 of this Plan.

10. Amendment of Plan.

a. Subject to the requirements of 30 V.S.A. § 218d, VGS or the DPS, jointly or separately, may request that this Plan be amended to modify its existing provisions or to add provisions.

b. If the request to amend is not made jointly by the parties, then the procedures of Paragraph 9 will apply to any request to amend the Plan.

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